UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al.*) Docket No. ER03-563-060

MOTION TO LODGE OF MAINE PUBLIC UTILITIES COMMISSION IN SUPPORT OF REQUEST FOR REHEARING

Pursuant to Rule 212 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2004), Maine Public Utilities Commission ("MPUC") hereby moves to lodge additional evidence in the above-captioned proceeding in support of its request for rehearing. Specifically, the MPUC requests that the Commission consider specific sections of the recently-issued Department of Energy ("DOE") National Electric Congestion Study ("Congestion Study"). A copy of the relevant sections of the study are attached hereto as Attachment A. This Congestion Study is relevant to the issue of whether the transition payments are reasonable for Maine consumers given export constraints that "limit[] receipt of generation output from Maine . . .into New England."[1]

I. BACKGROUND

On June 16, 2006, the Commission approved a settlement agreement which, among other things, sets fixed non-locational capacity rates for a four to five year period.[2] In its request for rehearing of the Settlement Order, the MPUC outlined evidence, ignored by the Settlement Order, which supported Maine's claim that lower transition rates should be applicable to Maine consumers. Specifically, MPUC referred to Dr. Austin's testimony which demonstrated, for example, that in July 2005, Maine was export

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[1] 2005 ISO-NE Regional System Plan at 45.

[2] *Devon Power, LLC,* 115 FERC ¶ 61,340 (2006) ("Settlement Order").

constrained 42.9 percent of the time and that ISO New England, Inc. ("ISO-NE") in its own 2005 Regional System Plan report concedes that Maine is export constrained.[3] Further, the MPUC provided information from a 2005 Reliability Report (issued by ISO-NE after the comment period on the settlement agreement) which stated that Maine's export constraints were binding in about "10.5% of the real-time hours during 2005."[4]

On August 1, 2006, ISO-NE filed a Motion for Leave to Answer and Answer. While ISO-NE had in its settlement comments flatly denied that Maine was export constrained, in the August 1 filing ISO responded to the evidence produced by the MPUC of Maine's export constraint with the assertion that Maine is not "meaningfully" export constrained. [5] ISO-NE asserts that, because some of the export constraints occur *near* but not *at* the New Hampshire border, the export constraint is not "meaningful." ISO also suggests that information from its own reports, cited by MPUC, should not be taken at face value when discussing binding export constraints and that the Commission should instead rely on a new chart devised by ISO-NE for the purpose of advancing its claim that Maine is not export constrained.

On August 8, 2006, DOE issued its Congestion Study which "examines congestion and transmission constraints in the U.S. portions of the Eastern and Western

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[3] Request for Rehearing and Motion for Clarification of the State of Maine Public Utilities Commission and the Maine Public Advocate ("MPUC Request for Rehearing"), July 17, 2006, citing the Affidavit of Thomas Austin and the Supplemental Affidavit of Thomas Austin, filed on respectively, on March 27, 2006 and April 5, 2006.

[4] MPUC Request for Rehearing at 16, citing ISO-NE 2005 Reliability Report at 21-22 (issued June 1, 2006) (emphasis added). The reliability report can be found at: http://www.iso-ne.com/pubs/arr/2005_reliability_report.pdf

[5] Motion for Leave to Answer, Answer, and Request for Expedited Consideration of ISO New England, Inc.., August 1, 2006 at 13.

Interconnections. . ." [6] The Congestion Study identified the most constrained paths for 2008 and further identified the top 100 and top 40 most constrained paths.[7] The Maine-NH interchange is included among the top 40 congested paths.[8] The Congestion Study also makes the following statement, about New England's Congestion Areas of Concern. "These [congestion] areas include the Maine generation pocket where too little transmission capacity is available to send more low-cost generation south."[9]

The Department of Energy met with ISO-NE on June 19, 2006 to discuss New England.[10] If ISO asserted facts to the DOE upon which the DOE relied to come to its conclusion that Maine is "generation rich," then that information ought to also be included in the record of this case.

II. ARGUMENT

The DOE Congestion Study is directly relevant both to the material fact and issue of law that underlie the MPUC request for rehearing. The material fact at issue is whether Maine is export constrained to a degree that it is "generation-rich" as described in the DOE report. The legal issue is whether the Commission's decision to impose the

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[6] Congestion Study at 1.

[7] For its study of congestion in New England, the Congestion Study relied primarily on data supplied by ISO-NE. See Congestion Study, Appendix I. One of the primary sources of data was the 2005 ISO-NE Regional System plan.

[8] *Id.* at 27, Figure 3-7.

[9] See also, Congestion Study at 4, comparing Maine's surplus generation and export constraint to load pockets, such as San Francisco or New York City. "[B]y contrast, transmission constraints cause Maine, which has far more generation than load, to be generation-rich."

[10] Congestion Study, Appendix G.

transition charges set forth in the settlement agreement upon Maine ratepayers is just and reasonable given Maine's current "generation rich" state.

The Congestion Study is fully consistent with the evidence supplied by the MPUC which shows that (1) Maine has a surplus of generation, (2) current transmission constraints limit the amount of generation that can be exported from Maine, and (3) these generation surpluses and transmission constraints have resulted in significant price separation in the energy market between Maine and the rest of New England. Moreover, the Congestion Study contradicts claims (made in this docket, but not elsewhere) by ISO-NE that Maine is not export-constrained or is not "meaningfully" export constrained.[11]

Wherefore, the MPUC respectfully requests that the Commission grant the instant motion to lodge in support of requests for rehearing in this proceeding.

Dated: September 8, 2006

Respectfully submitted,

Lisa Fink

Lisa Fink
Senior Staff Attorney
Maine Public Utilities Commission
242 State Street
Augusta, ME 04333
(207) 287-1389
Lisa.Fink@maine.gov

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[11] The credibility of ISO-NE's claim that Maine is not export constrained or "meaningfully" export constrained is further undermined by the fact that DOE relied, in part, on ISO-NE's 2005 Regional System Plan to determine that Maine's export constraint ranked in the top 40 constrained paths, while ISO-NE suggests that its own studies, including information derived from the same 2005 Regional System Plan, support its claim (in this docket) that Maine is not "meaningfully" export constrained.

CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010, I hereby certify that I have this day served, via electronic mail or first class mail, the foregoing document upon each party designated on the official service list compiled by the Secretary in this proceeding.

Dated at Augusta, Maine, this 8th day of September, 2006.

Lisa Fink

Lisa Fink

ATTACHMENT A

NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

AUGUST 2006

U.S. Department of Energy

1. Introduction

FEDERAL POWER ACT

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Sec. 216. SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES

(a) DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS—(1) Not later than 1 year after the date of enactment of this section and every 3 years thereafter, the Secretary of Energy . . ., in consultation with affected States, shall conduct a study of electric transmission congestion.

(2) After considering alternatives and recommendations from interested parties (including an opportunity for comment from affected States), the Secretary shall issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor.

* * * *

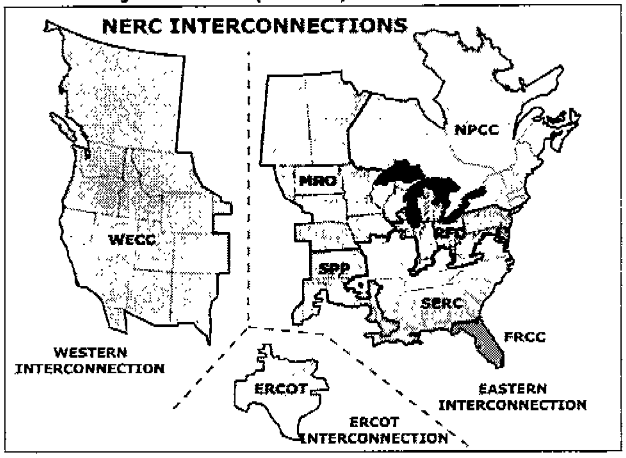
Section 1221(a) of the Energy Policy Act of 2005 added section 216 to the Federal Power Act (FPA), which directs the Secretary of Energy (the Secretary) to conduct a nationwide study of electric transmission congestion within one year after the date of enactment (i.e., by August 8, 2006) and every three years thereafter.[2]

The Secretary is also directed to issue a report based on the congestion study in which he may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a national interest electric transmission corridor." As specified in FPA section 216(a)(4), the Secretary, in exercising his authority to designate a national interest electric transmission corridor ("National Corridor," or "Corridor"), may consider the economic vitality and development of the corridor and markets served, the economic growth of the corridor and its end markets, including supply diversification and expansion, the Nation's energy independence, national energy policy, and national defense and homeland security.

As directed in the law, this study examines congestion and transmission constraints in the U.S. portions of the Eastern and Western Interconnections, but does not address the Electric Reliability Council of Texas, which is a third interconnection. (See Figure 1-1 for a map of the three interconnections, which together comprise the bulk power system in the U.S., much of Canada, and a small portion of Mexico.) Although this analysis does not address congestion and constraints outside the U.S., data on Canadian electricity generation, transmission, demand, cross-border flows, etc. were incorporated into the modeling conducted for the study because

[2]See Appendix A for the full text of section 1221(a) and (b).

Figure 1-1. Map of North American Electric Reliability Council (NERC) Interconnections



Source: NERC, 2006.

in both the Eastern and Western Interconnections, the electricity grids and wholesale markets are highly integrated systems.

1.1. Organization of This Study

Chapter 1 defines transmission congestion, transmission constraints, and transmission paths, describes the team that conducted the study, and documents the public outreach and consultation process used to date. To minimize confusion, the term "corridor" will be used only in reference to National Corridors and to multipurpose energy corridors that Federal departments are to designate on Federal lands under section 368 of the Energy Policy Act of 2005.[3]

Chapter 2 describes the approach and methods used to conduct this study (i.e., review of existing studies, historical data, and simulations of future grid congestion). Chapter 2 also reviews the assumptions and procedures used for the congestion modeling and then outlines modeling processes and basic data specific to each interconnection.

Chapters 3 and 4 present the congestion study results. Chapter 3 reviews the historical transmission constraints of the Eastern Interconnection, and then presents the findings of congestion modeling for 2008 and 2011. Chapter 4 presents similar results for the Western Interconnection for 2008 and 2015.

Based on the findings of Chapters 3 and 4, Chapter 5 identifies **Critical Congestion Areas**—areas of the country where it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe. Second, Chapter 5 identifies **Congestion Areas of Concern**, which are areas where a large-scale congestion problem exists or may be emerging, but more information and analysis is needed to determine the magnitude of the problem and the likely relevance of transmission expansion and other solutions. Third, the chapter identifies **Conditional Constraint Areas**—areas where significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity. DOE believes that affirmative government and corporate decisions

Comparison of This Study and DOE's 2002 *National Transmission Grid Study*

In May 2002, DOE published its *National Transmission Grid Study*, in response to direction provided by the Administration's *National Energy Policy*. The Grid Study presented an assessment of transmission congestion developed using the POEMS model, an electric system simulation tool. In several respects, findings from the Grid Study have been reconfirmed by the analysis presented in this report, including the economic importance of relieving severe congestion to benefit consumers and the basic geographic patterns of congestion. There are, however, important differences that preclude direct comparison of the results from the two studies. First, the results presented in the Grid Study are now four years old; some of the most severe problems flagged there have been or are being addressed and hence are no longer of interest in this study. Second, the current study uses modeling tools that focus more precisely on specific constraints and congested areas.

[3]See Appendix A for the text of section 368.

need to be made in the next few years to begin development of some of these generation resources and the associated transmission facilities.

Chapters 6 and 7 describe the next steps DOE envisions in working with stakeholders to address issues and concerns associated with the three kinds of congestion areas it has identified. Chapter 7 also discusses ways to improve and strengthen future congestion studies. This is the first congestion study DOE has conducted in response to its obligations under the Federal Power Act, as amended. It was done with extensive cooperation and support from regional transmission planning groups and organizations, states, and electric companies. DOE appreciates this support.

1.2. Definitions of Key Terms and Concepts

For the purposes of this study, DOE will use the definitions and concepts presented below. Also, see text box, next page, for additional information about the use of these terms.

Transmission congestion and constraints

Congestion occurs when actual or scheduled flows of electricity on a transmission line or a related piece of equipment are restricted below desired levels—either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The term *transmission constraint* may refer either to a piece of equipment that limits electricity flows in physical terms, or to an operational limit imposed to protect reliability. When a constraint prevents the delivery of a desired level of electricity across a line in real time, system operators must "redispatch" generation (that is, increase output from a generator on the customer's side of the constraint, and reduce generation on the other side), cut wholesale transactions previously planned to meet customers' energy demand at lower cost, or, as a last resort, reduce electricity deliveries to consumers. All of these actions have adverse impacts on electricity consumers.

Transmission constraints exist in many locations across the Nation. However, transmission congestion is highly variable, especially on an hour-to-hour or day-to-day basis. When longer periods of time are examined, recurrent patterns of congestion can be identified. A transmission facility's carrying capacity can vary according to ambient temperatures, the distribution of loads and generation across the grid, and the resulting patterns of electricity flows. The grid is not necessarily most congested (in terms of the volume or value of desired flows curtailed by constraints) during periods of peak demand, because under those conditions most low-cost generation capacity is being used to serve nearby customers and less output from such sources is available for export to more distant areas.

The cost of transmission congestion

Transmission congestion always has a cost—because when constraints prevent delivery of energy from less expensive sources, energy that is deliverable from more expensive sources must be used instead. It is not always cost-effective, however, to make the additional investments that would be required to alleviate congestion. Where transmission congestion occurs frequently because of a major constraint, the wholesale prices for electricity will differ on each side of the constraint; across a region, prices will usually vary in different locations as a function of the availability and costs of energy imports and local generation relative to load.

In an area with an organized wholesale electricity market and publicly posted information on minute-by-minute, location-specific wholesale energy prices, congestion costs can be accurately estimated by summing the value of low-cost transactions that cannot be completed due to transmission constraints, and comparing those to the more expensive value of the generation or imports forced by the constraint. ISOs and RTOs routinely publish monthly and annual congestion cost estimates, noting that the magnitude of those estimates is often driven by the cost of electricity (and underlying fuel costs) as much as by the magnitude of transmission constraints.[4] Similarly, ISOs and RTOs estimate the degree to which congestion in specific areas would be alleviated by transmission upgrades, because major reductions in congestion mean bill savings for electricity customers.[5] Congestion also occurs in areas where the grid is managed by individual integrated utilities rather than by regional grid operators; however, since transmission, generation and redispatch costs are less visible in these areas, the costs of congestion are not as readily identifiable.

Reliability

As the term is used here, reliability refers to the delivery of electricity to customers in the amounts desired and within accepted standards for the frequency, duration, and magnitude of outages and other adverse conditions or events. *Load pockets* are created when a major load center (such as a large city like San Francisco or New York) has too little local generation relative to load and must import much of its electricity via transmission from neighboring regions. For example, most of California is currently a generation-short load pocket; by contrast, transmission constraints cause Maine, which has far more generation than load, to be generation-rich. Because it is frequently difficult to site and build efficient new generation within a city, or to build additional transmission into a city, the resulting load pocket will often experience congestion—meaning it cannot import as much low-cost energy as it would like, and the city's electricity provider(s) must operate one or more existing power plants inside the city more intensively to ensure that all customer needs are met, although at higher cost. If electricity demand inside the load pocket grows quickly without being checked by energy efficiency and demand response, the load pocket may face a looming reliability problem, with too little supply (local generation plus transmission-enabled imports) relative to demand—whether in actual terms or according to accepted rules for safe grid operation. In such cases, it is necessary for the transmission owner(s) serving the load pocket to resolve the reliability problem as quickly as possible.

In the case of a load pocket, there are three primary ways to deal with a long-term congestion problem:

1. Build new central-station generation within the load pocket;
2. Build new or upgrade transmission capacity (some combination of lines and other equipment such as transformers and capacitors) to enable distant generators to serve a portion of the area's load; or
3. Reduce electricity demand (and net import needs) within the load pocket, through some combination of energy efficiency, demand response, and distributed generation.

The three options can be used singly or in combination to solve a transmission constraint problem flexibly and cost-effectively. Generation and transmission, however, are costly, time-consuming solutions that often face opposition. Demand-side options tend to be under-utilized because they have high transaction costs with results that may be less certain and less controllable. It should also be noted that there are a variety of transmission-only solutions to any specific transmission problem; not every transmission project (or combination of projects) will provide equal congestion relief, nor will it provide equal reliability or economic benefits to everyone in the affected region.

[4]See, for example, PJM's statement that congestion costs resulting from constraints in the Allegheny Mountain area totaled $747 million in 2005, with another $464 million on the Delaware River path that year. See http://www.pjm.com/contributions/news-releases/2006/20060307-national-interest-transmission-corridors.pdf for additional detail. Organized markets offer various hedging mechanisms to enable transmission purchasers to protect themselves and prevent the full cost of congestion from driving up their total delivered electricity costs.

[5]It is important to note that the purpose of this study was to identify areas experiencing significant congestion, as opposed to estimating the net value of actions to address the congestion. See, for example, the CAISO's estimate that transmission upgrades and operational improvements completed in 2005 reduced summer congestion costs by more than $54 million in just two months (http://www.caiso.com/docs/2005/10/19/2005101913044018437.pdf), and that three newly approved transmission projects will "reduce the costs of managing transmission bottlenecks and maintaining adequate generation for local reliability by $30 million per year" (http://www.caiso.com/17dc/17dc9dc64cfa0.pdf).

3. Congestion and Constraints in the Eastern Interconnection

This chapter addresses the Eastern Interconnection, reviewing first the paths that have historically been constrained, and then presenting the simulation results for those parts of the grid that are expected to be constrained and congested in 2008 and 2011. This chapter offers general rather than detailed information on the constraints studied and the simulation modeling results, to avoid offering unnecessary detail about vulnerable elements of the Nation's critical energy infrastructure.[19]

3.1. Historical Transmission Constraints and Congestion Areas

Historical transmission constraints are locations on the grid where it has frequently been necessary to interrupt electric transactions or redirect electricity flows because the existing transmission capacity is insufficient to deliver the desired energy without compromising grid reliability. The constraints shown below were documented by the regional reliability councils or other major transmission entities in the Eastern Interconnection. As noted in Chapter 1, the amount and quality of the transmission studies—and therefore the available information about the grid—varies from region to region across the interconnection. A list of the studies reviewed is included in Appendix I.

Historical transmission constraints are presented below by region. (See maps in Figures 3-1 through 3-6.) In some cases, a constraint is shown as a point, which represents a load pocket with limited transmission into the area to serve its loads. In other cases, the constraint is shown as an arrow, indicating that electricity flows across that constraint tend to be directional, with the generation sources located toward the base of the arrow and the loads somewhere beyond its point. No attempt has been made to depict the magnitude of the transactions that were limited or the level of congestion caused by each constraint; therefore, the arrows do not reflect a magnitude (of electricity flow or economic value). The numbers do not represent a rank order, but correspond to the constraints listed below each map.

These constraints are generally known to transmission owners, planners, and wholesale electricity buyers across the Eastern Interconnection. In some cases, transmission upgrades or expansions are already being planned or are under construction to alleviate a significant reliability or economic problem caused by the constraint. Most of the constraints shown, however, require operational mitigation for day-to-day management, and no commitments for physical capital upgrades have been made.

The congested areas indicated on the graphics below may be affected by one or more local transmission constraints—for instance, the southwest Connecticut area is currently affected by six different transmission constraints. In many cases, the constraint closest to the indicated area is not the most limiting element on the path because some other constraint further "upstream" limits the path's flows to a greater degree.

Constraints in the New England region

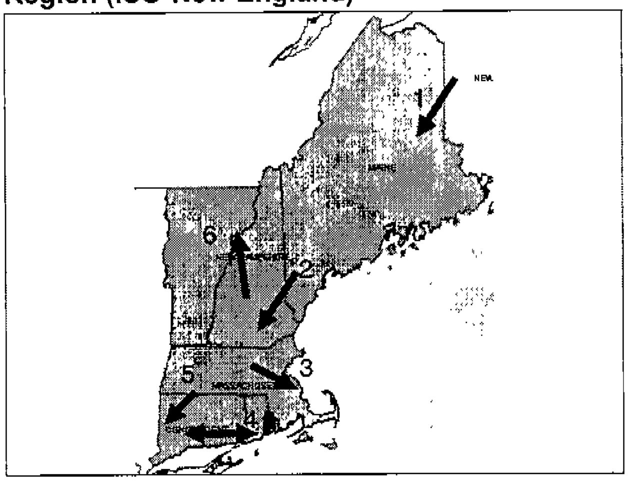
Figure 3-1 shows the following constraints in the New England region:

1. New Brunswick to Maine
2. Maine-New Hampshire Interface
3. Boston Import

[19] A reader seeking more detailed information should contact the transmission planning department of the relevant transmission owner or grid operator, or Department of Energy staff.

4. Southern New England East-West Flows
5. Southwest Connecticut
6. Northwestern Vermont from New Hampshire

Figure 3-1. Constraints in the New England Region (ISO-New England)



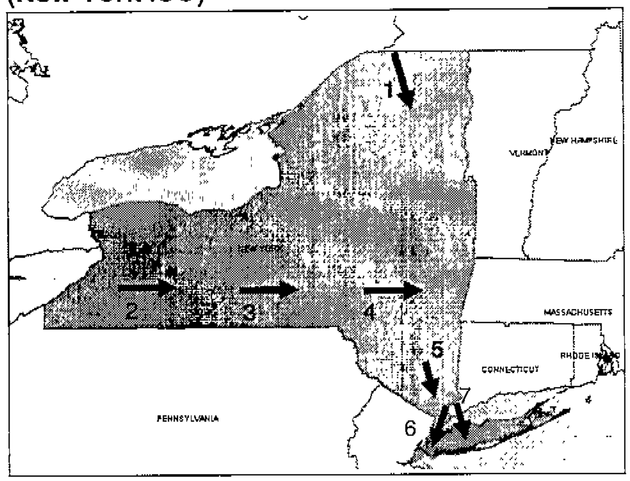
Many of the constraints identified in this region are expected to be eased by transmission projects that are either now under construction or approved by appropriate government officials for construction. Nonetheless, the New England region faces growing electricity supply challenges that new transmission could mitigate. New England has a growing load and many of its older power plants are close to retirement, so the region will need to consider new investments in some combination of local generation, transmission to bring new low-cost power into the area (e.g., hydropower from Quebec), and more energy efficiency and demand response to better manage loads. The area now depends to a substantial extent upon natural gas and oil as generation fuels, which in today's markets leads to high retail electricity prices.

Constraints in the New York region

Figure 3-2 shows the following constraints in the New York region:

1. Moses South Interface
2. Dysinger East Interface
3. West Central Interface
4. Central East and Total East Interface
5. UPNY-ConEd Interface
6. Westchester to New York City
7. Westchester to Long Island

Figure 3-2. Constraints in the New York Region (New York ISO)



All of New York's constrained transmission paths have a common characteristic—they move power from the west, south and north to the loads in and around New York City and Long Island. The New York metropolitan area is a major load pocket with significantly less generation than load, and is heavily import-dependent. The area's electricity rates are high, due in considerable part to the dependence of local generation on natural gas and oil fuels.

Constraints in the PJM region

Figure 3-3 shows the following constraints in the PJM region:

1. From Allegheny Power System to PEPCO and Dominion
2. The Western Interface and Central Interfaces of "Classic PJM"[20]
3. The Eastern Interface of "Classic PJM"
4. Branchburg transformer
5. PJM to New York City

[20] PJM has expanded substantially in recent years. The term "Classic PJM" is used to refer to PJM's footprint before the expansion, when PJM's territory consisted of eastern Pennsylvania, New Jersey, much of Maryland, Delaware, and the District of Columbia.

Similarly, because of close import ties and multiple electrical interfaces, significant changes in transmission or generation capacity or flows in New York or the Mid-Atlantic will also affect system operations in New England, Ontario, Michigan, and the upper Midwest. This interdependence will continue to grow. Given that the economy of the Nation and the well-being of its citizens depend heavily upon a strong, reliable, electricity infrastructure for this area, the Department believes it is advisable to develop an inter-regional, long-term approach to dealing with the area's challenges.

The Department recommends that transmission planners, regulators and stakeholders from PJM, NYISO, ISO-NE, MISO, Quebec and Ontario work jointly to analyze the long-term inter-regional challenges and to identify and support solutions that will meet the needs of the wider area as a whole, as well as its components. The Department does not intend that any of the RTO-level initiatives and analyses now under way should be put on hold or delayed while a new level of inter-regional analysis is conducted. The challenge is to find an appropriate balance between the upgrades and other actions that are needed urgently in the near term, and the need to develop realistic concepts for what this critical portion of the Eastern Interconnection should look like twenty and thirty years from now. This long-term effort will be hampered by many uncertainties, and it will be important to ensure that near-term initiatives are robust "no regrets" projects, suitable to a wide range of possible futures.

New England Congestion Area of Concern

Chapter 3 showed that several locations in New England today face significant transmission congestion, but the problems in most of these areas are being addressed through planned transmission projects. These areas include the Maine generation pocket (where too little transmission capacity is available to send more low-cost generation south), the Boston load pocket (where more local generation, more import capacity, more demand reduction, or some combination are needed), southwest Connecticut (where the local grid is very weak), and northern Vermont (where demand has been growing rapidly). ISO-NE and the transmission owners in the region have pursued a systematic reliability assessment and transmission planning process over the past several years, and new transmission projects and other efforts are now under way that are intended to substantially ease these problems.

Beyond these projects, ISO-NE has recently begun analysis of a possible new 345 kV transmission project linking Rhode Island, southern Massachusetts, and central Connecticut. This project could ease reliability concerns in Rhode Island and Massachusetts by strengthening the network, while enabling delivery of needed additional electricity supplies into western Connecticut.[46]

Looking 10-15 years ahead, however, the New England region faces growing electricity supply challenges that new transmission could help to mitigate. New England has a growing load and many of its older power plants are close to retirement, so the region will need to undertake new investments in local generation, transmission to bring new low-cost power into the area (for instance, hydropower from Quebec), and more energy efficiency and demand response to better manage loads. The area now depends to a substantial extent upon natural gas and oil as generation fuels, leading (in today's markets) to high retail electricity prices.

5.3. Congestion Areas in the Western Interconnection

In contrast to the East, congestion in the West is more tightly focused geographically, and in some areas more contingent upon the development of

[46] See National Grid's comments to DOE's February 2, 2006 Notice of Inquiry. National Grid says that "the transmission system in southern New England experiences transmission constraints in Rhode Island, Connecticut, and the Springfield, Massachusetts areas. Limitations on Connecticut import capability that currently result in out-of-merit generation costs are projected to become a reliability issue by 2009 at which time available generation and transmission will no longer be adequate to meet resource adequacy requirements. The ISO-NE RSP05 indicates that the . . . area would benefit from transmission reinforcements that better integrate the load serving and generation within Massachusetts, Rhode Island, and Connecticut, and enhance the grid's ability to move power from east-to-west and vice versa."

years modeled. Future electricity production costs are difficult to predict due to the variability and uncertainty of fuel costs, environmental costs, operating costs, and other factors.

Interconnection electricity demands and generation resources were held constant across all of the fuel price scenarios for a given year, as were the transmission system's physical and electrical characteristics. Thus, fuel prices—translated through the geographic distribution of power plants consuming those fuels—were the principal drivers of transmission congestion and costs as they varied between scenarios.

Identifying the most constrained paths

In running the three fuel price cases for 2008 and 2011, as directed by DOE, CRAI identified the highest-ranking hundred constraints for each of the four congestion metrics for each scenario, and for both model years:

- 100 highest binding hours; this identifies the constrained paths that are most consistently and heavily used, and most often require out-of-merit redispatch of generating units to prevent affected facilities from over-loading.
- 100 highest U90; these are the constrained paths that are most frequently within 10% of becoming binding.
- 100 highest shadow price; these constrained paths have the most persistently high shadow prices and cause price spikes in end-use markets.
- 100 highest congestion rent; these are the paths that raise delivered energy costs the most over the course of the year.

As one might expect, some constrained paths ranked high on more than one list. As directed by DOE, CRAI compiled a single list of 171 constrained paths as the most constrained for the 2008 base case; a similar process was followed to identify the most constrained paths for the other five scenarios (2008 high and low fuel price case, and 2011 base, high and low fuel price case). Then CRAI looked across all six scenarios to identify the paths that were near the top of the list in every scenario, and thus would be constrained under almost every year and fuel price; 118 paths fit this pattern. Last, CRAI sorted these top 118 paths by market area.

Figure 3-7 shows the most congested paths identified by the Eastern Interconnection modeling. A few observations:

- Many of the most congested paths are located within regional markets while others cross the boundaries between two markets.
- A significant number of the most congested paths appear on the tie lines between two control areas.
- Given load growth patterns and the size of transmission utility footprints, some of the most congested paths are located within individual control areas, particularly in the Southeast.

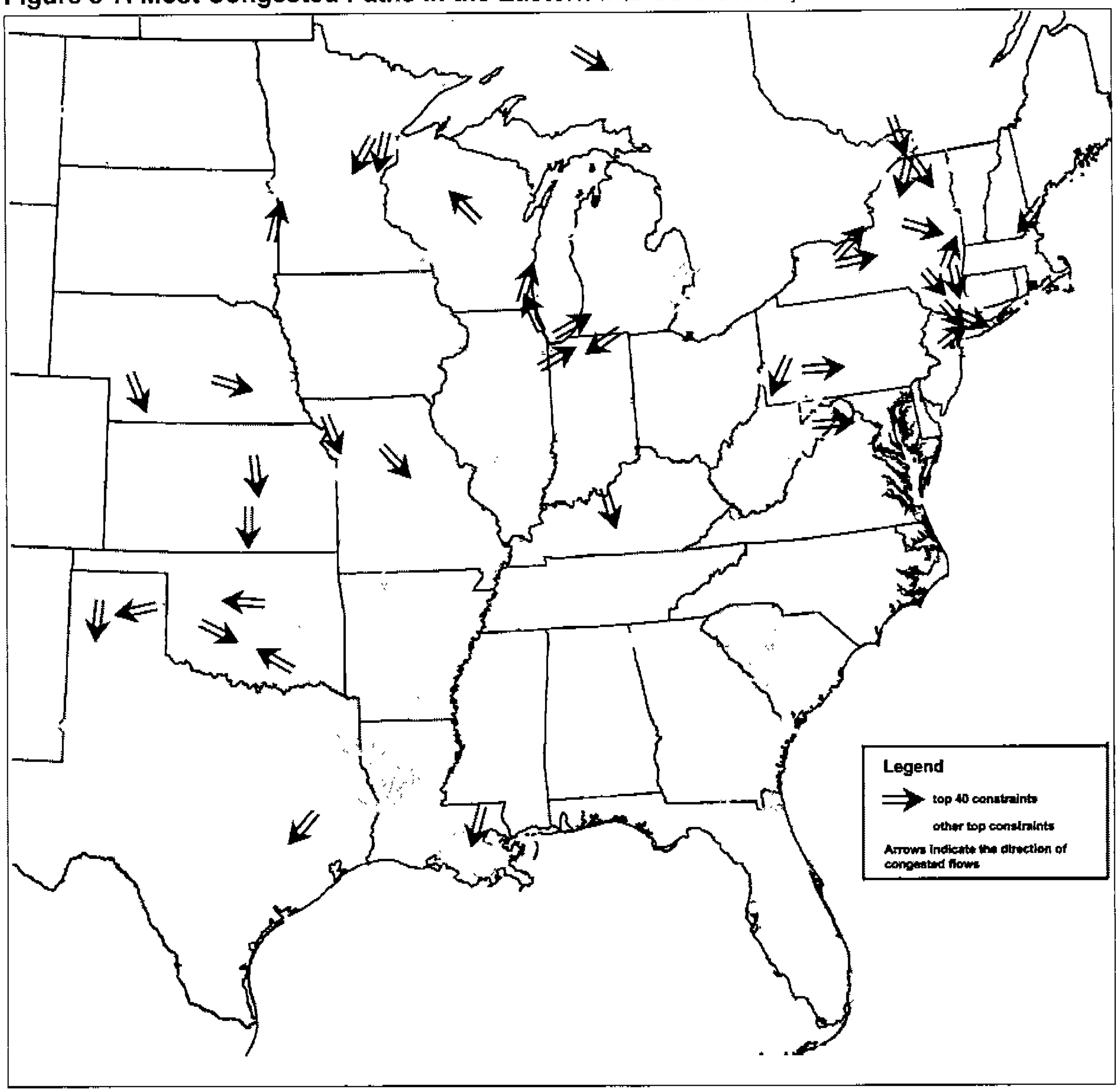
As shown in Figure 3-7, the simulation modeling for the Eastern Interconnection found patterns and locations of congestion and constraints that closely parallel the constraints known from historical patterns. Note that the areas where congestion is most highly concentrated are eastern PJM and the state of New York. Significant congestion is indicated in Louisiana, but this simulation used supply and demand data for the Gulf Coast region as it was prior to the 2005 hurricanes. Demand in this area is now much lower, which presumably reduces the congestion.

One area where the modeled results differed from those reported in existing regional analyses was Florida. DOE's analysis of the Eastern Interconnection showed a significant constraint at the border between Georgia and Florida, and other constraints within Florida. Although these constraints are not as high-ranking (in terms of U90 and congestion rent) as others in the interconnection, the DOE analysis showed higher line loadings and numbers of binding hours than are reflected in available regional analyses.

Officials at the Florida Reliability Coordinating Council (FRCC) suggest two possible reasons for these differences in analytic results. One is that the model used in DOE's analysis may not accurately reflect obstacles to trade in the Georgia-Florida border area, and the second is that dispatch in this area of Florida is based on marginal losses, but the model assumed dispatch on the basis of average losses.

Concerning the obstacles to trade, the model used here assumes economically efficient transactions will occur everywhere in the Eastern Interconnection, including the Georgia-Florida border area. This assumption is typical of simulation models. Deviating from that assumption in an analytically justifiable way is not feasible without more detailed information and data about the obstacles in question, so that they can be accurately portrayed in the model. Average retail electricity rates in Florida were 24% higher in 2004 than those in Georgia and 31% higher than those in Alabama;[22] this implies the existence of significant barriers to trade of some kind. The treatment of line losses will be considered in determining changes needed to improve future national, regional, and inter-regional congestion analyses. (See Chapter 7 for additional discussion.)

Figure 3-7. Most Congested Paths in the Eastern Interconnection, 2008 Simulation



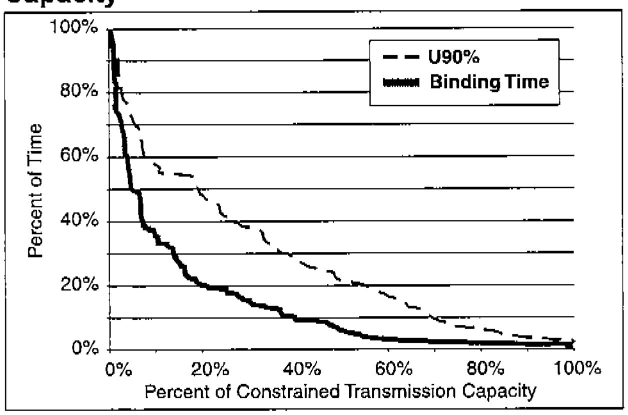
Note: Louisiana is shown as having significant congestion, but this simulation is based on the Gulf Area system as it was prior to the 2005 hurricanes. Electricity demand in the area is now significantly lower, and one would expect congestion to

[22] Energy Information Administration, *State Electricity Profiles 2004*, June 2006.

Other observations based on the congestion modeling

Figure 3-8 confirms expected relationships for those paths that are constrained. First, most constraints are heavily loaded in relatively few hours per year—for instance, 80% of constrained transmission capacity is at its binding limit less than 20% of the year. Second, many of the constraints that sometimes operate at or above 90% of their operating limits reach the binding level (100% of limit) much less frequently. For instance, the ten percent of transmission capacity most heavily used is at 90% usage in 56% of the year, but reaches binding levels only 34% of the time.

Figure 3-8. Time That Constraints Are Binding Relative to Level of Constrained Transmission Capacity

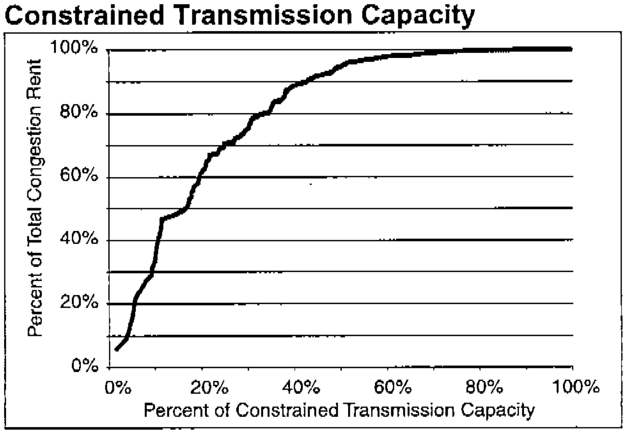


Source: Eastern Interconnection 2008 Base case.

Figures 3-9 and 3-10 confirm two more expected relationships. Figure 3-9 shows that total congestion rent[23] rises as the amount of constrained transmission capacity increases. Thus, 20% of constrained capacity accounts for 60% of congestion rent, and 50% accounts for nearly 95% of congestion rent. Congestion is not evenly spread around the system, and a relatively small portion of constrained transmission capacity causes the bulk of the congestion cost that is passed through to consumers. **This means that a relatively small number of selective additions to transmission capacity could lead to major economic benefits for many consumers.**

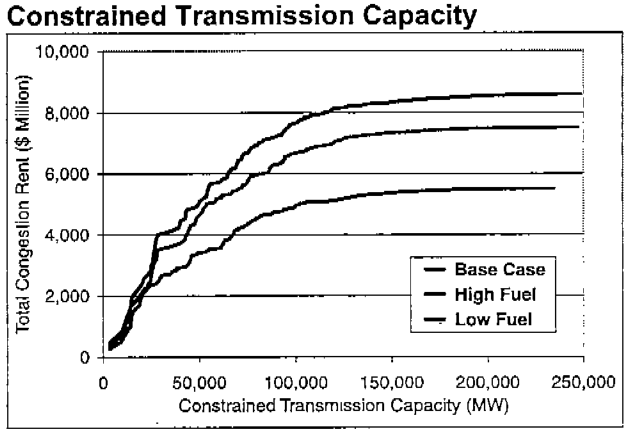
Figure 3-10 shows that the relative level of congestion rent tracks with relative fuel prices—as fuel prices rise, a given transmission constraint will impose higher and higher costs upon the customers located on the expensive, generation-short side of the constraint, because the shadow price of each constraint has fuel prices embedded in the underlying cost of power production foregone due to the constraint. In areas such as the Northeast, where the marginal generation close to loads tends to be older, less efficient oil- and gas-fired units, new transmission construction will enable the import of less expensive coal, nuclear, hydropower, or more

Figure 3-9. Congestion Rent Versus Constrained Transmission Capacity



Source: Eastern Interconnection 2008 Base case.

Figure 3-10. Congestion Rent Versus Constrained Transmission Capacity



Source: Eastern Interconnection 2008 Base case and Fuel Sensitivity case.

[23] Annual congestion rent is calculated by multiplying the marginal production cost of pushing one more MWh through a transmission constraint times the number of MWh that flow through the constraint, and summing the products for the hours during a year when that constraint is limiting.

efficient gas-fired generation, and create millions of dollars of savings in delivered electricity costs, while improving grid reliability.[24]

Congestion rent, as a fraction of total electricity cost, was found to be relatively low in the eastern modeling. For the 2008 base case, the total cost of served load was about $171 billion, and congestion rent totaled 4.7%; for the 2011 high case, the total cost of served load was about $202 billion, and congestion rent totaled 5.1%.

A few specifics about the congestion findings from the modeling:

- 46% of the constrained capacity had average shadow prices greater than $1.00/MWh in all hours.
- 10% of the constrained capacity showed all-hours congestion prices greater than $10/MWh.
- 20% of constrained capacity accounted for 60% of the congestion rent.
- 42% of the constrained capacity accounted for 90% of the congestion.

Reconciling congestion modeling and historical constraints

The top 118 constraints in the Eastern Interconnection identified through modeling and ranking were compared to the historical congestion areas and constraints to verify that the model was properly identifying problem areas on the grid. In most cases, the modeling results were consistent with the historical data.

- Almost every constraint shown as a critical historical constraint identified in the regional studies was identified in the modeling as affecting significant transmission paths.
- Six historical constraints were not confirmed in modeling as binding; upon investigation, it was determined that for five of those constraints, the NERC Multiregional Modeling Working Group (MMWG) load flow case includes transmission upgrades that relieve the historical constraint (for instance, modeled upgrades eliminate part of the Eau Claire-Arpin constraint from Minnesota to Wisconsin, as well as upgrades in Georgia that ease constrained flows into Atlanta). In the case of a constraint in northeast Kansas, as confirmed by SPP, the historical constraint causes primarily non-firm curtailments.
- The modeling identified many more constraints than the regional studies. Most of these did not affect any significant paths, either because the constraint has primarily a local impact, or because other constraints are more binding upon the path. For example, neither the Southwest Connecticut nor the Boston import constraints bind in the model, because upstream and downstream constraints limit flows into the congestion area more tightly.

The net result of this comparison is that the modeling for the Eastern Interconnection effectively identified the important grid congestion areas and transmission constraints.

[24] Economic congestion, as calculated and expressed here, is not intended to be a proxy for true production cost savings, even though reducing congestion does reduce overall electricity production costs.

Appendix G

Outreach Meetings Held Regarding the Congestion Study

Organization/Event	Outreach Type	Location	Date
National Conference of State Legislatures (NCSL)	Presentation at NCSL National Conference	Seattle, WA	August 18, 2005
Southern States Energy Board	Presentation at Utility Restructuring Task Force	Atlanta, GA	August 27, 2005
Midwest State Energy Office	Presentation for Web Cast	Web Cast	August 31, 2005
National Association of State Energy Officials (NASEO)	Presentation at NASEO 2005 Annual Meeting	New York, NY	September 12, 2005
Hunton & Williams	Presentation at Seminar	Washington, D.C.	September 19, 2005
Committee on Regional Electric Power Cooperation (CREPC)	Presentation	San Diego, CA	September 20, 2005
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	September 26, 2005
Western Electricity Coordinating Committee (WECC)	Presentation at Joint Committee Meetings	Phoenix, AZ	September 29, 2005
Imperial (Calif.) Irrigation District	Meeting	Washington, D.C.	October 3, 2005
National Council on Electricity Policy Annual Meeting	Presentation	Chicago, IL	October 4, 2005
Bonneville Power Administration (BPA)	Meeting	Washington, D.C.	October 27, 2005
Transmission Access Policy Group (TAPS)	Presentation	Washington, D.C.	November 7, 2005
American Public Power Association (APPA)	Presentation at APPA's Energy Policy Act of 2005 Seminar	Washington, D.C.	November 10, 2005
National Wind Coordinating Committee (NWCC)	Presentation at Transmission and Wind Strategy: Issues and Opportunities conference	Conference call	November 10, 2005
National Association of Regulatory Utility Commissioners (NARUC)	Presentation at NARUC Annual Convention	Palm Springs, CA	November 14, 2005
New York State Public Service Commission	Meeting	Albany, NY	December 20, 2005
North American Electric Reliability Council (NERC)	Conference call	Conference call	December 22, 2005
ISO-RTO Council	Conference call	Conference call	January 10, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Conference call	Conference call	January 11, 2006
ISO-New England (ISO-NE)	Conference call	Conference call	January 12, 2006
Law Firm of Bracewell & Giuliani	Meeting	Washington, D.C.	January 17, 2006
American Electric Power (AEP)	Meeting	Washington, D.C.	January 31, 2006
Upper Great Plains Transmission Coalition (UGPTC)	Conference call	Conference call	January 31, 2006
Energy Policy Act of 2005: Electric Transmission and Distribution Future R&D Needs (DOE conference)	Presentation at conference	Tallahassee, FL	February 1, 2006
National Association of State Energy Officials (NASEO)	Presentation at NASEO Energy Outlook Conference	Washington, D.C.	February 7, 2006

Organization/Event	Outreach Type	Location	Date
National Independent Power Producers Coalition (NIPPC)	Conference call	Conference call	February 8, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Presentation NARUC Winter Meeting	Washington, D.C.	February 14, 2006
Western Electricity Coordinating Council	Presentation	Salt Lake City, Utah	February 15, 2006
National Electricity Delivery Forum	Presentation	Washington, D.C.	February 15-16, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Presentation at NARUC Meeting	Washington, D.C.	February 22, 2006
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	February 28, 2006
Canadian Electricity Association Power Marketer's Council	Presentation	Washington, D.C.	March 1, 2006
U.S.-Canada Forum	Presentation at the Forum at the Woodrow Wilson Center	Washington, D.C.	March 2, 2006
PJM Interconnection	Meeting	Washington, D.C.	March 3, 2006
Federal Energy Regulatory Commission (FERC)	Meeting with FERC staff	Washington, D.C.	March 9, 2006
Infocast Transmission Summit (conference)	Presentation	Washington, D.C.	March 14, 2006
North American Electricity Working Group	Presentation	La Jolla, CA	March 22, 2006
Innovation Investments, ICF Consulting	Meeting	Washington, D.C.	March 27, 2006
Public Technical Conference and Web Cast on DOE Congestion Study and Criteria for Designation of National Interest Electric Transmission Corridors	Presentations	Chicago, IL	March 29, 2006
Federal Energy Regulatory Commission (FERC), PJM Interconnection	Meeting with FERC staff and PJM Interconnection	Washington, D.C.	April 3, 2006
Committee on Regional Electric Power Cooperation (CREPC)	Presentation at CREPC meeting	Portland, OR	April 4, 2006
ABB	Meeting	Washington, D.C.	April 7, 2006
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	April 10, 2006
Burns & McDonnell Transmission Line Symposium	Presentation	Kansas City, MO	April 27, 2006
North American Electric Reliability Council (NERC) Stakeholders Meeting	Presentation	Arlington, VA	May 1, 2006
U.S. DOE Wind Program	Meetings with staff	Washington, D.C.	May 2006
PJM Interconnection	Meeting	Washington, D.C.	May 4, 2006
American Transmission Company	Meeting	Washington, D.C.	May 11, 2006
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	May 11, 2006
Organization of MISO States (OMS) Board	Conference call	Conference call	May 11, 2006
Southern Company	Meeting	Birmingham, AL	May 22, 2006
Electric Power Supply Association (EPSA)	Meeting	Washington, D.C.	May 30, 2006
U.S. DOE Nuclear NP2010 Program	Conference calls with staff	Conference call	May, June 2006
Community Power Alliance	Presentation at the Community Power Alliance Breakfast	Washington, D.C.	June 6, 2006
Platt's Infrastructure Investment Conference	Presentation	Washington, D.C.	June 6, 2006
Florida Public Service Commission (FPSC)	Meeting	Tallahassee, FL	June 15, 2006

Organization/Event	Outreach Type	Location	Date
Florida Reliability Coordinating Council (FRCC)	Meeting	Tallahassee, FL	June 15, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Conference call with Electricity Committee	Conference call	June 16, 2006
ISO-New England (ISO-NE)	Meeting	Holyoke, MA	June 19, 2006
Edison Electric Institute (EEI)	Presentation at EEI Annual Convention	Washington, D.C.	June 20, 2006
Allegheny Power, ICF Consulting	Meeting	Washington, D.C.	June 21, 2006
National Grid	Meeting	Washington, D.C.	July 28, 2006

Appendix H

General Documents or Data Reviewed for the Congestion Study

1. Electricity Advisory Board, Electric Resources Capitalization Subcommittee, U.S. Department of Energy, "Competitive Wholesale Electricity Generation: A Report of the Benefits, Regulatory Uncertainty, and Remedies to Encourage Full Realization Across All Markets," September 2002.
2. Electric Transmission Constraint Study, FERC OMOI, December 2003.
3. Electricity Advisory Board, U.S. Department of Energy, "Transmission Grid Solutions Report," September 2002.
4. Federal Energy Regulatory Commission, "Testimony of Karl Pfirrmann, President, PJM Western Region, PJM Interconnection, L.L.C.," Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources—Docket No. AD05-3-000.
5. Federal Energy Regulatory Commission, "Remarks of Audrey Zibelman, Executive Vice President, PJM Western Region, PJM Interconnection, L.L.C.," Transmission Independence and Investment—Docket No. AD05-5-000 and Pricing Policy for Efficient Operation and Expansion of the Transmission Grid—Docket No. PL03-1-000.
6. National Commission on Energy Policy, "Siting Critical Energy Infrastructure, An Overview of Needs and Challenges, A White Paper Prepared by the Staff of the National Commission on Energy Policy," June 2006.
7. U.S. Department of Energy, "National Transmission Grid Study," May 2002.
8. U.S. Department of Energy, "Comments to the Designation of National Interest Electric Transmission Bottlenecks (NIETB) Notice of Inquiry," Appended 10/15/04.

Appendix I

Documents or Data Reviewed for the Eastern Interconnection Analysis

1. 2004 State of the Market Report—New York ISO, Potomac Economics.
2. 2005 Minnesota Biennial Transmission Report.
3. 2005 Triennial Review of Resource Adequacy, March 2006, NYISO.
4. APPA Issue Brief: Joint Ownership of Transmission, January 2006.
5. Big Stone Certificate of Need and Route Permit.
6. Buffalo Ridge Incremental Generation Outlet Transmission Study (BRIGO Study).
7. Cambridge Energy Research Associates Study (2004) "Grounded in Reality: Eastern Interconnection."[68]
8. CAPX 2020 Vision Study – CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs. (Minnesota 2005).
9. Electric Transmission Constraint Study (December 19, 2001) posted on the FERC website.
10. FERC Form 715s.
11. Florida-Southern Interface Study for 2005 Summer & 2005-06 Winter Bulk Electric Supply Conditions (October 2004).
12. Impacts of Lincoln – Circle 230kV in Kansas, May 2005, SPP Engineering Department, Planning Section.
13. Iowa/Southern Minnesota Exploratory Study.
14. ISO New England 2004 Annual Markets Report.
15. ISO New England Regional System Plan 2005 (October 2005).
16. Maryland Public Service Commission, "Reply Comments of the Staff of the Maryland Public Service Commission in the Matter of the Inquiry Into Locational Marginal Prices in Central Maryland During the Summer of 2005"—Case No. 9047.
17. MEN 2002 Interregional Transmission System Reliability Assessment.
18. Michigan Exploratory Study Preliminary Study Report (Draft), October 2005, MISO.
19. Michigan Public Service Commission, "Final Staff Report of the Capacity Need Forum," January 3, 2006.
20. Midwest Transmission Expansion Plan (MTEP) of the Midwest ISO. (The Northwest Exploratory Study and Midwest ISO West RSG Consolidated Study included in the MTEP should be reviewed for possible NIETC designations.)
21. MISO 2003 Transmission Expansion Plan.
22. MISO Transmission Expansion Plan 2005 (June 2005).
23. NERC 2005 Long-Term Reliability Assessment.
24. NERC 2005 Summer Assessment.
25. NERC 2005/2006 Winter Assessment.
26. NERC TLR Data.
27. New England 2005 Triennial Review of Resource Adequacy, ISO New England, November 2005.
28. Northeastern Coordinated System Plan.

[68] Reviewed but considered confidential, so not used.

29. NPCC 2004 Report of the CP–10 Working Group Under the Task Force on Coordinated Planning.

30. NPCC Reliability Assessment for Summer 2005.

31. NYISO 2004 Intermediate Area Transmission Review of the New York State.

32. NYISO 2005 Load & Capacity Data.

33. NYISO Comprehensive Reliability Planning Process (CRPP) Reliability Needs Assessment (December 2005).

34. NYISO Comprehensive Reliability Planning Process Supporting Document and Appendices For The Draft Reliability Needs Assessment (December 2005).

35. NYISO Comprehensive Transmission Plan.

36. NYISO Electric System Planning Process, Initial Planning Report (October 6, 2004).

37. NYISO Operating Study Winter 2004-05 (November 2004).

38. NYISO Transmission Performance Report (August 2005).

39. PJM Regional Transmission Expansion Plan 2005 (September 2005).

40. PJM, MISO, NYISO, and ISO-NE Realtime and Day-ahead Constraint Data.

41. PJM Interconnection, L.L.C., "Comments of PJM in Response to the MD PSC Notice of Inquiry"—Case Number 9047.

42. Project Mountaineer, Work Group Meeting, Sheraton Four Points Hotel, Baltimore, MD, August 3, 2005.

43. Reports produced by MAIN and ECAR (provided to U.S. Department of Energy by EEI).

44. SERC Reliability Review Subcommittee's 2005 Report to the SERC Engineering Committee (June 2005).

45. SPP RTO Expansion Plan 2005–2010 (September 2005).

46. Southwest Minnesota Twin Cities 345 kV EHV Development Study.

47. Southwest Power Pool's Kansas/Panhandle Sub-Regional Transmission Study, January 26, 2006.

48. Southwest Power Pool Intra-Regional Appraisal and Study Observation—2005 Summer Peak Transmission Assessment, May 2005, SPP Engineering Department, Planning Section.

49. Southwest Power Pool Intra-Regional Appraisal and Study Observation 2005/06 Winter Peak Transmission Assessment—Draft, Nov 2005, SPP Engineering Department, Planning Section.

50. Southwest Power Pool Intra-Regional Appraisal and Study Observation 2005/06 Winter Peak Transmission Assessment—Nov 2005, SPP Engineering Department, Planning Section.

51. Southwest Power Pool Intra-Regional Appraisal and Study Observation 2014 Summer Peak Transmission Assessment, Nov 2005, SPP Engineering Department, Planning Section.

52. System Reliability Assurance Study (SRAS) prepared by Consolidated Edison Company of New York in December 2005.

53. Trans-Allegheny Interstate Line Project, A 500 kV Transmission Line Through the AP Zone; Published February 28, 2006 by Allegheny Power.

54. U.S. Department of Energy, "National Transmission Grid Study," May 2002.

55. U.S. Department of Energy Transmission Bottleneck Project Report, Consortium for Electric Reliability Technology Solutions (CERTS), March 2003.

56. VACAR 2004-2005 Winter Stability Study Report (March 2004)

57. VACAR 2005 Summer Reliability Study Report (April 2004).

58. VACAR 2007 Summer Reliability Study Report (February 2002).

59. VASTE 2005 Summer Reliability Study Report (May 2005).

60. VASTE 2005-06 Winter Study Report (November 2005).
61. VEM 2004 Summer Reliability Study Report (May 2004).
62. VEM 2004-2005 Winter Reliability Study Report (November 2004).
63. VST(E) 2011 Summer Study Report (November 2004).
64. VSTE 2008 Summer Study Report (November 2005).
65. Western Area Power Administration's Dakota Wind Study (2005).